Electricity Report

28 February – 5 March 2016

Introduction

The AER is required to publish the reasons for significant variations between forecast and actual price and is responsible for monitoring activity and behaviour in the National Electricity Market. The Electricity Report forms an important part of this work. The report contains information on significant price variations, movements in the contract market, together with analysis of spot market outcomes and rebidding behaviour. By monitoring activity in these markets, the AER is able to keep up to date with market conditions and identify compliance issues.

Spot market prices

Figure 1 shows the spot prices that occurred in each region during the week 28 February to 5 March 2016. There were four occasions where the spot price in Queensland was greater than \$2000/MWh and one occasion in both Victoria and South Australia where the spot price was greater than \$1900/MWh.

Figure 1: Spot price by region (\$/MWh)

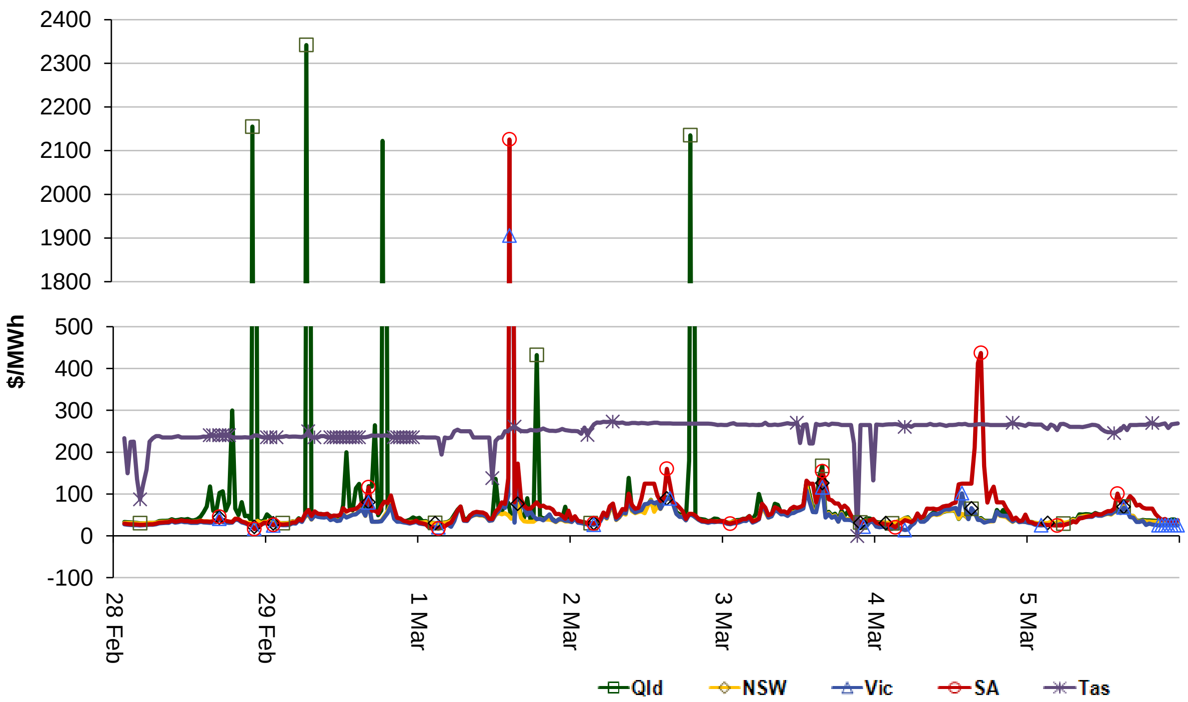


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

Figure 2: Volume weighted average spot price by region ($/MWh)

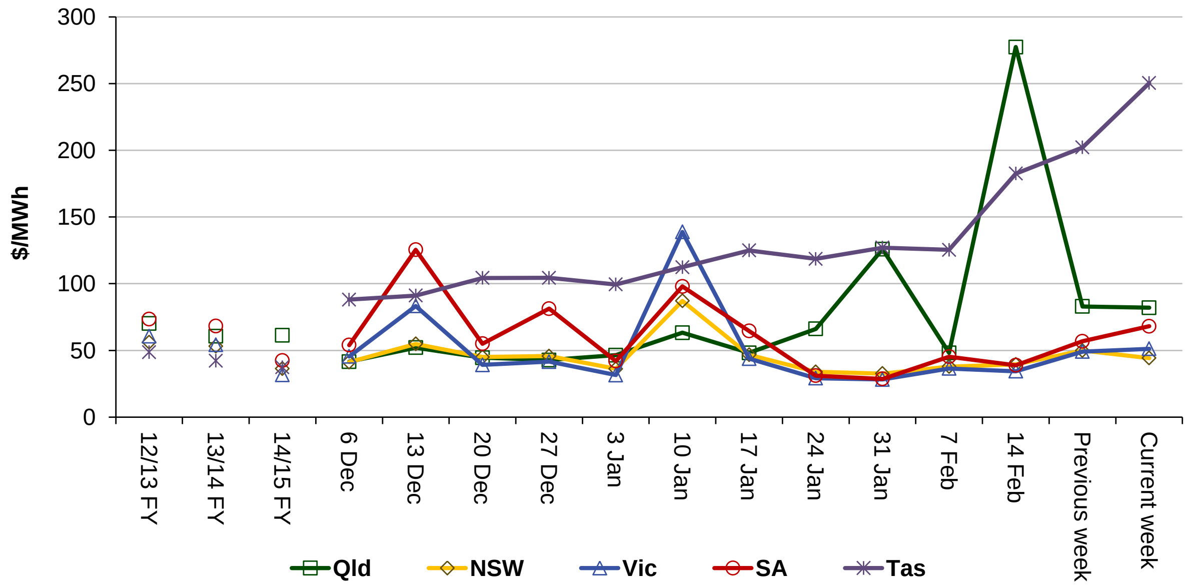


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	82	44	51	68	250
14-15 financial YTD	72	37	32	41	38
15-16 financial YTD	58	46	43	61	78

Longer-term statistics tracking average spot market prices are available on the AER website.

Spot market price forecast variations

The AER is required under the National Electricity Rules to determine whether there is a significant variation between the forecast spot price published by the Australian Energy Market Operator (AEMO) and the actual spot price and, if there is a variation, state why the AER considers the significant price variation occurred. It is not unusual for there to be significant variations as demand forecasts vary and participants react to changing market conditions. A key focus is whether the actual price differs significantly from the forecast price either four or 12 hours ahead. These timeframes have been chosen as indicative of the time frames within which different technology types may be able to commit (intermediate plant within four hours and slow start plant within 12 hours).

There were 195 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2015 of 133 counts and the average in 2014 of 71. Reasons for the variations for this week are summarised in Table 2. Based on AER analysis, the table summarises (as a percentage) the number of times when the actual price differs significantly from the forecast price four or 12 hours ahead and the major reason for that variation. The reasons are classified as availability (which means that there is a change in the total quantity or price offered for generation), demand forecast inaccuracy, changes to network capability or as a combination of factors (when there is not one dominant reason). An instance where both four and 12 hour ahead forecasts differ significantly from the actual price will be counted as two variations.

Table 2: Reasons for variations between forecast and actual prices

	Availability	Demand	Network	Combination
% of total above forecast	12	38	0	4
% of total below forecast	4	24	0	18

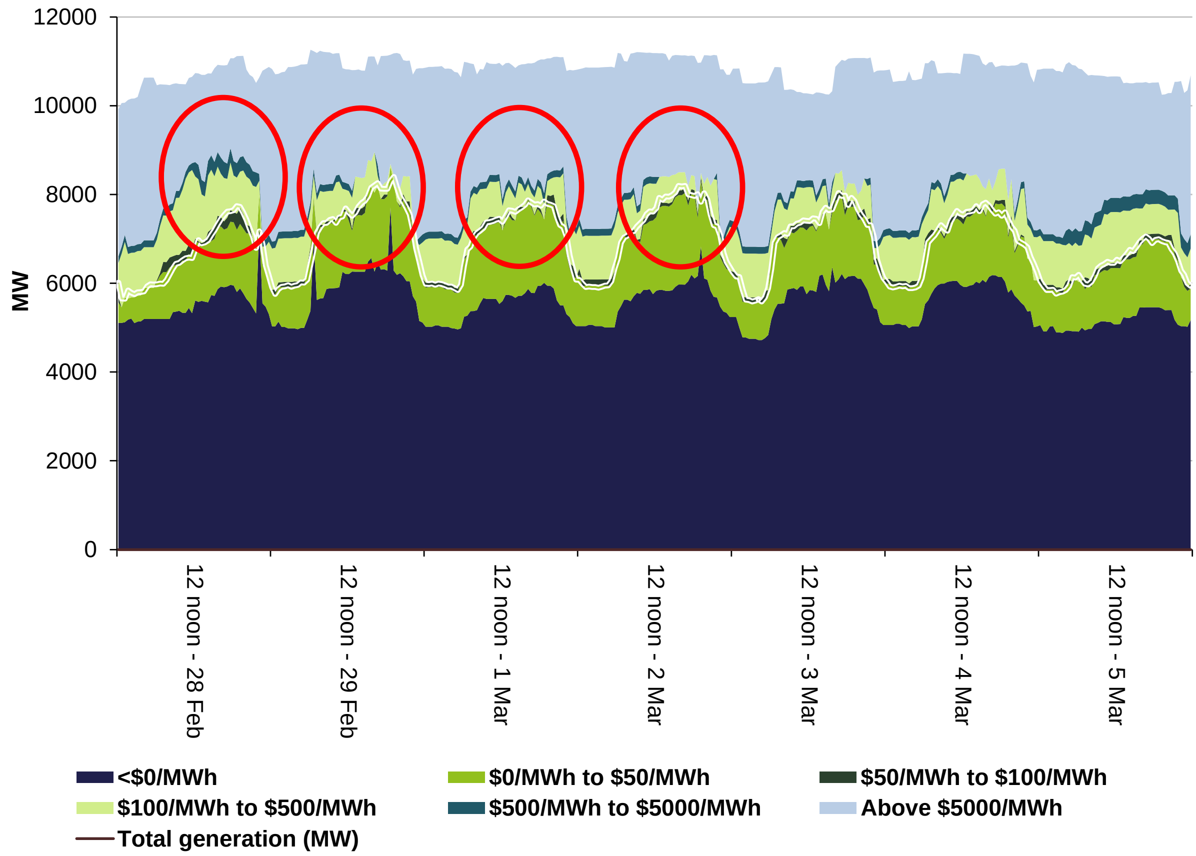
Note: Due to rounding, the total may not be 100 per cent.

Generation and bidding patterns

The AER reviews generator bidding as part of its market monitoring to better understand the drivers behind price variations. Figure 3 to The red ellipses on Figure 6 highlights the periods during the week where there were high prices. These events are covered in detail in the section below.

Figure 7 show, the total generation dispatched and the amounts of capacity offered within certain price bands for each 30 minute trading interval in each region.

Figure 3: Queensland generation and bidding patterns



The red ellipses on Figure 3 highlight the period during the week where rebidding by participants led to high prices. These events are covered in detail in the section below.

Figure 4: New South Wales generation and bidding patterns

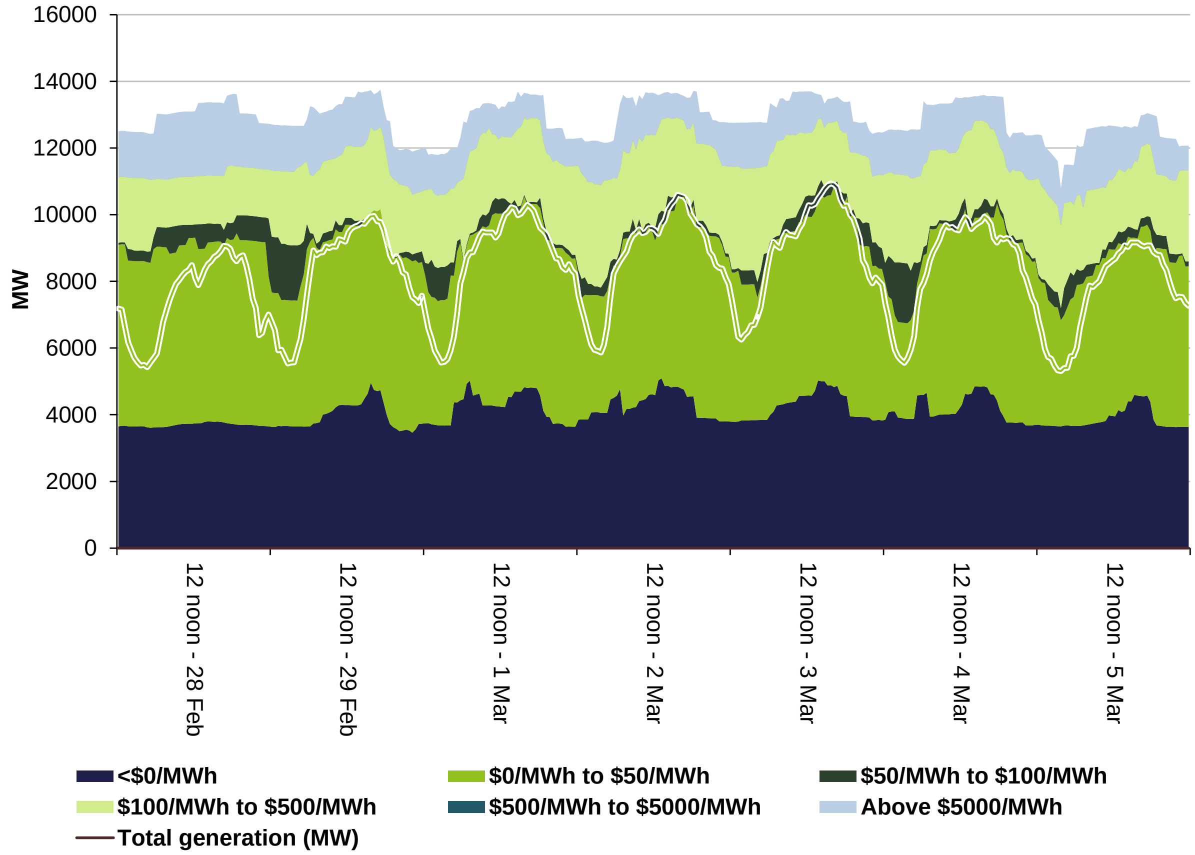


Figure 5: Victoria generation and bidding patterns

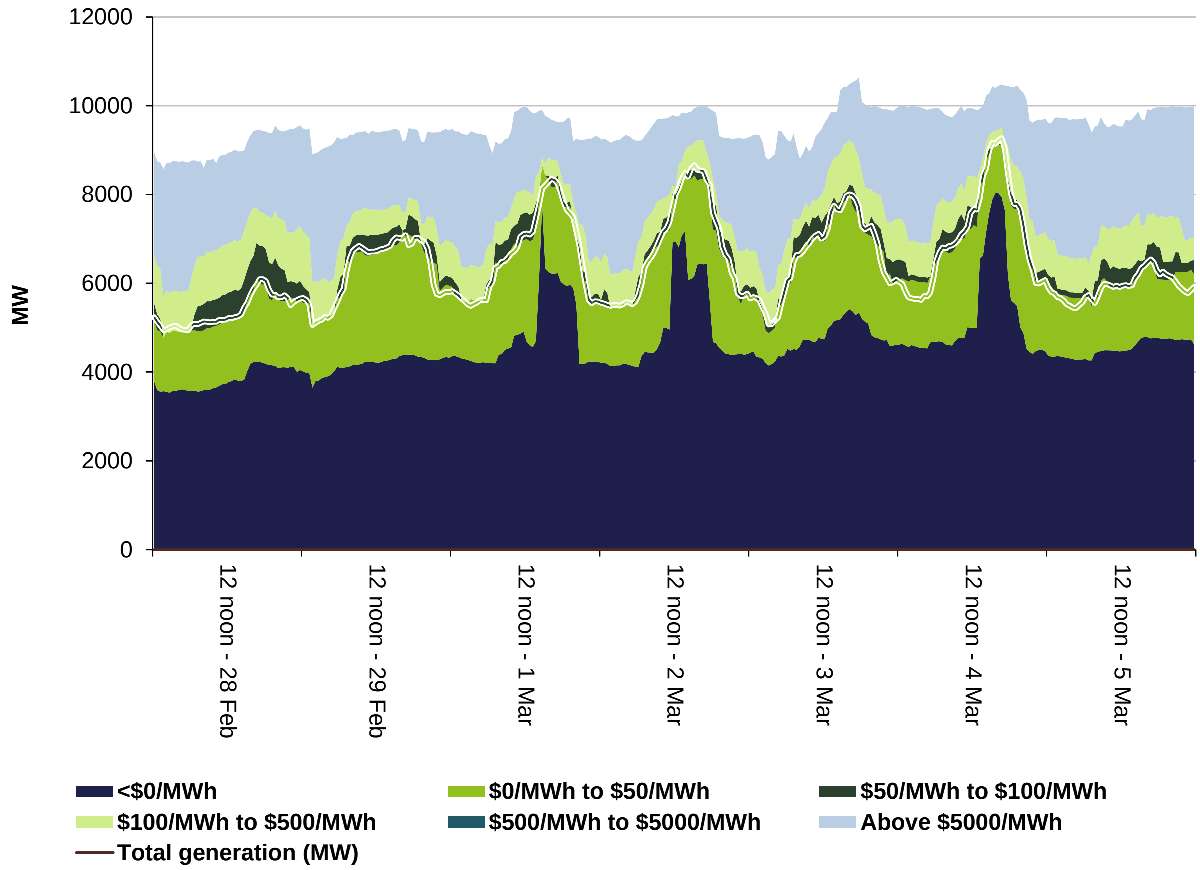
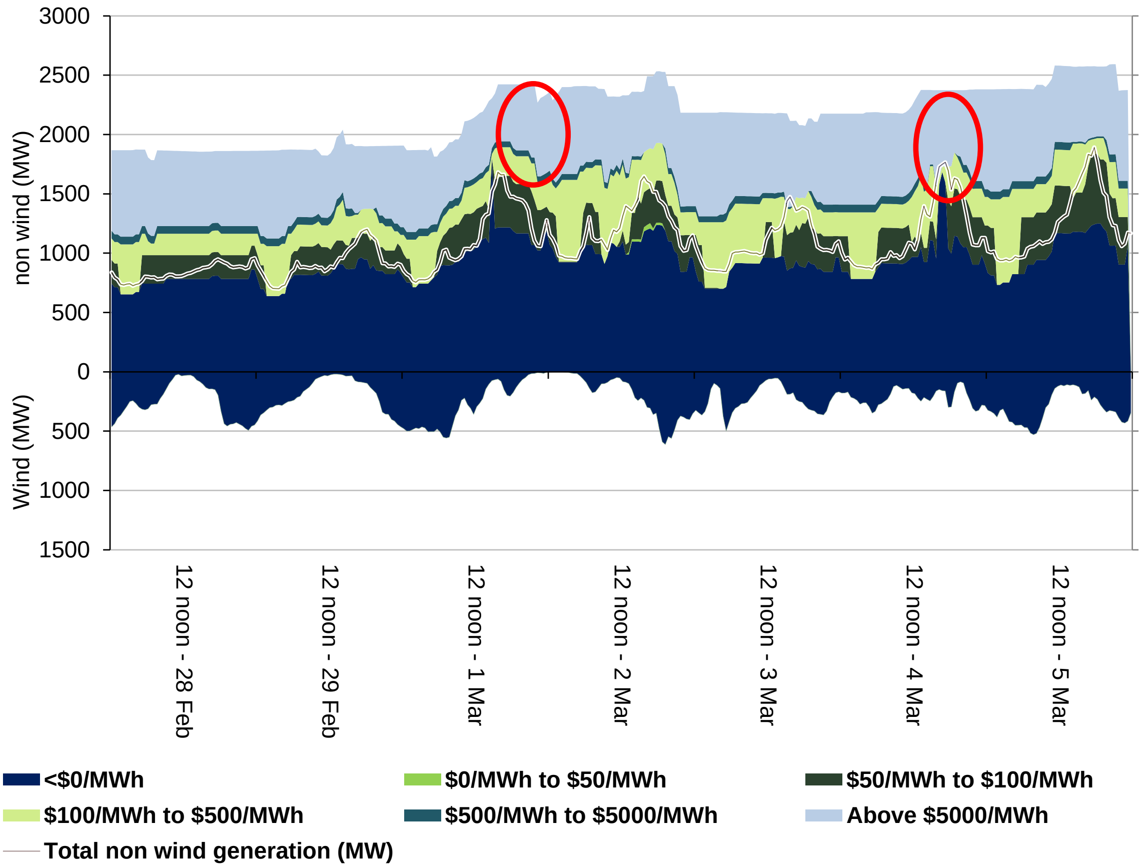
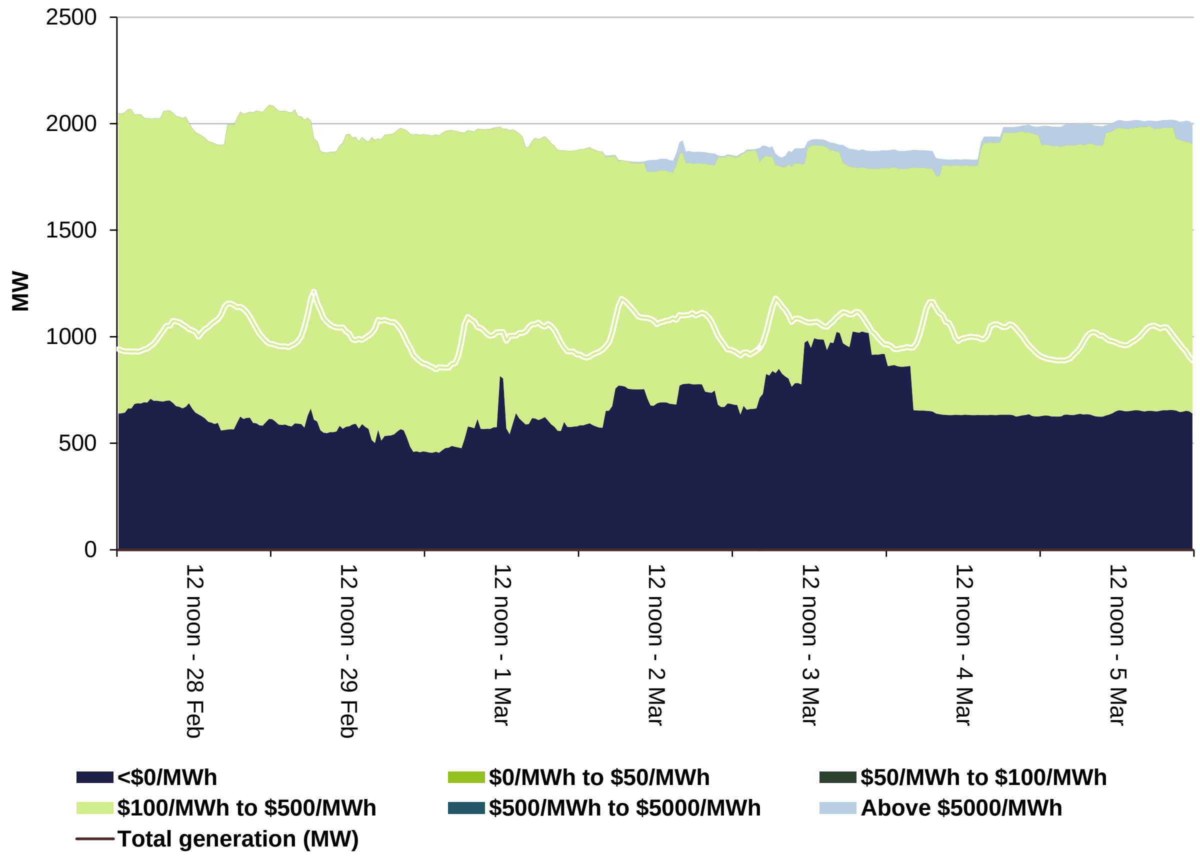


Figure 6: South Australia generation and bidding patterns



The red ellipses on Figure 6 highlights the periods during the week where there were high prices. These events are covered in detail in the section below.

Figure 7: Tasmania generation and bidding patterns



Frequency control ancillary services markets

Frequency control ancillary services (FCAS) are required to maintain the frequency of the power system within the frequency operating standards. Raise and lower regulation services are used to address small fluctuations in frequency, while raise and lower contingency services are used to address larger frequency deviations. There are six contingency services:

- fast services, which arrest a frequency deviation within the first 6 seconds of a contingent event (raise and lower 6 second)
- slow services, which stabilise frequency deviations within 60 seconds of the event (raise and lower 60 second)
- delayed services, which return the frequency to the normal operating band within 5 minutes (raise and lower 5 minute) at which time the five minute dispatch process will take effect.

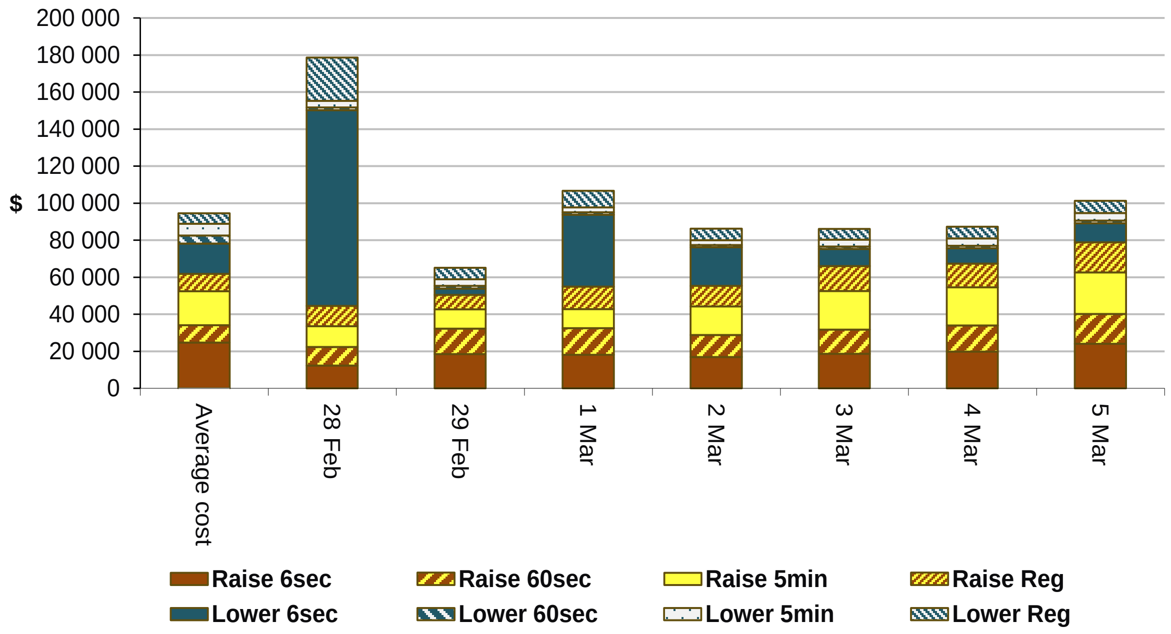
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $430 000 or around 0.2 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $281 000 or less than 1 per cent of energy turnover in Tasmania.

Figure 8 shows the daily breakdown of cost for each FCAS for the NEM, as well as the average cost since the beginning of the previous financial year.

Figure 8: Daily frequency control ancillary service cost



Detailed market analysis of significant price events

We provide more detailed analysis of events where the spot price was greater than three times the weekly average price in a region and above $250/MWh or was below -$100/MWh.

Queensland

There were seven occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $82/MWh and above $250/MWh.

Sunday, 28 February

Table 3: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
7 pm	299.91	48.95	299.91	7884	7736	7761	11 097	11 129	11 167
10.30 pm	2155.04	41.98	36.00	6607	6713	6704	10 664	10 979	11 241

Conditions at the time saw demand up to 150 MW higher than forecast four hours ahead and availability was close to forecast four hours ahead.

Table 4: Rebids for the 7 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.10 pm		Millmerran Energy Trader	Millmerran	140	7	13 800	15:09 A RRP ABOVE 5MIN PD – SL
3.19 pm		Callide Power Trading	Callide C	66	-1000	13 800	1518A PRICE ABOVE PD – SL
5.37 pm		CS Energy	Kogan Creek	-40	14	N/A	1736P SCC ASH LEVEL HIGH-SL
5.57 pm		QGC Sales	Condamine	41	-1000	12 497	5:56 PM P CHANGE IN PLANT CAPABILITIES SL
5.57 pm		Stanwell	Barron Gorge	25	-1	13 800	1737P MANAGE WEIR LEVEL SL
6.26 pm	6.35 pm	Millmerran Energy Trader	Millmerran	50	7	13 800	18:25 A CHANGE IN PD PRICE - SL
6.26 pm	6.35 pm	Callide Power Trading	Callide C	40	-1000	13 800	1823A CHANGE IN PD PRICE - SL

At 6.35 pm Millmerran and Callide's' rebids became effective and there was an 80 MW increase in demand; the dispatch price increased, to $300/MWh from $97/MWh at 6.30 pm. The price remained at $300/MWh for the entire trading interval.

Table 5: Rebids for the 10.30 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.52 pm		Origin Energy	Mt Stuart	-255	13 800	N/A	1848A CONSTRAINT MANAGEMENT – N^^Q_NIL_B1 SL
8.57 pm		CS Energy	Gladstone	150	300	13 800	2055A CHANGE IN QLD GENERATION-MT STUART-SL
9.58 pm	10.05 pm	ERM Power	Oakey	162	1400	12 889	2157A CHANGE IN QLD DEMAND 5M DISPATCH 6927MW VS 30M PD 6995MW

At 10.05 pm there was a 59 MW increase in demand and the ERM rebid became effective. With other lower price generation either ramp rate limited or fully dispatched, the dispatch price for 10.05 pm reach $12 889/MWh, set by Oakey. A number of participants responded to the 5 minute forecast high price, rebidding capacity from high to low prices, causing the price to fall to $18/MWh at 10.10 pm.

Monday, 29 February

Table 6: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
7 am	2342.03	41.98	35.50	6679	6676	6571	11 237	11 225	11 225

Conditions at the time saw demand and availability close to that forecast four hours ahead.

Table 7: Rebids for the 7 am trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.31 am	6.40 am	Millmerran Energy Trader	Millmerran	230	7	13 800	06:28 A CHANGE IN QNI PD - SL
6.42 am	6.50 am	Callide Power Trading	Callide C	100	-1000	13 800	0639A CHANGE IN QNI PD - SL

At 6.50 am there was a 99 MW increase in demand and the Callide C rebid became effective. With lower priced generation either fully dispatched, ramp rate limited or stranded, the dispatch price increased from $62/MWh at 6.45 am to $13 789/MWh at 6.50 am. In response to the 5 minute high price forecast, capacity was rebid from high to low prices and the price fell to $33/MWh at 6.55 pm.

Table 8: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
5.30 pm	264.25	37.63	399.69	8206	8072	8238	11 117	11 123	11 148
7 pm	2122.26	37.30	345.73	8132	8008	8157	11 150	11 132	11 177

Conditions at the time saw demand around 130 MW higher than forecast four hours ahead but close to that forecast 12 hours ahead. Availability was close to that forecast.

Table 9: Rebids for the 5.30 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.12 pm		Millmerran Energy Trader	Millmerran	59	7	13 800	16.11 A -134MW CHANGE Q P5M DISPGEN DI 1625 RUN
4.58 pm	5.05 pm	CS Energy	Gladstone	50	36	13 800	1657P MILL LIMIT-SL
4.58 pm	5.05 pm	Callide Power Trading	Callide C	86	-1000	13 800	1658A INCREASE IN P5MIN RRP FOR DI 1705
5.01 pm	5.10 pm	Millmerran Energy Trader	Millmerran	60	7	13 800	17:01 A RRP ABOVE 5MIN PD FOR DI 1705
5.18 pm	5.25 pm	CS Energy	Gladstone	105	<300	13 800	1717A INTERCONNECTOR CONSTRAINT-QNI BINDING NORTH-SL

As a result of the above rebids, and with lower priced generation fully dispatched, the dispatch increased from $49/MWh at 5 pm to $346/MWh at 5.05 pm. Dispatch prices then ranged from $200/MWh to $346/MWh for all but one dispatch interval of the 5.30 pm trading interval.

Table 10: Rebids for the 7 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.26 pm	6.35 pm	Millmerran Energy Trader	Millmerran	60	7	13 800	18:22 A -95MW CHANGE QNI P5M FLOW DI 0715 RUN 0625/0620
6.26 pm	6.35 pm	Callide Power Trading	Callide C	66	-1000	13 800	1823A -95MW CHANGE QNI P5M FLOW DI 0715 RUN 0625/0620
6.33 pm	6.40 pm	Stanwell	Stanwell	80	49	13 800	1830A QNI TRANSMISSION CONSTRAINT DI1830
6.33 pm	6.40 pm	Stanwell	Tarong	40	25	13 800	1830A QNI TRANSMISSION CONSTRAINT DI1830

At 6.40 pm there was a 128 MW increase in demand, this combined with the above rebids and lower price generation being either fully dispatched, ramp rate limited or trapped, saw the dispatch price increase from $72/MWh at 6.35 pm to $12 499/MWh at 6.40 pm. In response to a 5 minute high price forecast participants rebid capacity from high to low prices and the dispatch fell to $75/MWh at 6.45 pm.

Tuesday, 1 March

Table 11: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
7 pm	432.22	42.63	92.11	7847	7685	7822	11 023	11 157	11 044

Conditions at the time saw demand around 160 MW higher than forecast four hours ahead and availability was around 130 MW lower than forecast four hours ahead.

Table 12: Rebids for the 7 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
5.23 pm		Stanwell	Stanwell	100	49	>346	1710A CHANGE IN QLD GENERATION
5.23 pm		Stanwell	Tarong	100	<60	>300	1710A CHANGE IN QLD GENERATION
6.26 pm	6.35 pm	Callide Power Trading	Callide C	106	-1000	13 800	1824A -72MW CHANGE Q P5M DISPGEN DI 0650 RUN 0625/0620
6.27 pm	6.35 pm	Millmerran Energy Trader	Millmerran	85	7	13 800	18:27 A -72MW CHANGE Q P5M DISPGEN DI 0650 RUN 0625/0620
6.40 pm	6.50 pm	Millmerran Energy Trader	Millmerran	60	7	13 800	18:39 A 103$ CHANGE Q P5M RRP DI 0650 RUN 0640/0635
6.41 pm	6.50 pm	CS Energy	Gladstone	125	<36	13 800	1840A INTERCONNECTOR CONSTRAINT-QNI BINDING NORTH-SL
6.42 pm	6.50 pm	Stanwell	Stanwell	20	346	1400	1835A MATRERIAL CHANGE IN GENERATION B2PS & OAKEY DI1835

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.42 pm	6.50 pm	Stanwell	Tarong	80	300	1400	1835A MATERIAL CHANGE IN GENERATION B2PS & OAKEY

As a result of the above rebids, and with lower priced generation fully dispatched, prices rose from $97/MWh at 6.35 pm to $200/MWh at 6.40 pm, and then to $300/MWh at 6.45 pm. At 6.50 pm, when the rebids from Millmerran Energy Trader, CS Energy and Stanwell became effective, the dispatch price increased to $1400/MWh before returning to around $300/MWh for the rest of the trading interval.

Wednesday, 2 March

Table 13: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
7.30 pm	2135.13	67.50	64.91	7707	7766	7671	11 084	11 129	11 115

Conditions at the time saw demand and availability close to forecast.

Table 14: Rebids for the 7.30 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.55 pm	7.05 pm	Millmerran Energy Trader	Millmerran	130	7	13 800	18:54 A RRP ABOVE PD DI 1855
6.56 pm	7.05 pm	Callide Power Trading	Callide C	106	-1000	13 800	1855A RRP ABOVE PD DI 1855
6.59 pm	7.10 pm	CS Energy	Gladstone	100	<36	13 800	1859A DISPATCH PRICE HIGHER THAN 30MIN FORECAST-SL
7.12 pm	7.20 pm	Stanwell Corporation	Stanwell	100	49	13 800	1910A QNI TRANSMISSION CONSTRAINT DI1910
7.12 pm	7.20 pm	Stanwell Corporation	Tarong	200	<60	13 800	1910A QNI TRANSMISSION CONSTRAINT DI1910
7.13 pm	7.20 pm	Callide Power Trading	Callide C	40	-1000	13 800	1913A INCREASE IN ROSS DEMAND

At 7.20 pm the dispatch price increased to $12 497/MWh, from $97/MWh at 7.15 pm, when Stanwell and Callide Powers rebids became effective. In response to the high price participants rebid capacity from high to low prices and the dispatch fell to $34/MWh at 7.25 pm.

Victoria

There was one occasion where the spot price in Victoria was greater than three times the Victoria weekly average price of $51/MWh and above $250/MWh.

Tuesday, 1 March

Table 15: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
3 pm	1905.34	61.77	62.19	7371	7050	6900	9901	9910	9885

Conditions at the time saw demand 321 MW higher than forecast four hours ahead and 470 MW higher than forecast 12 hours ahead. Availability was close to forecast. A planned outage was forcing flow out of Victoria and into New South Wales at around 380 MW. Prices were aligned with those in South Australia.

At 2.55 pm there was a 210 MW demand increase. With limited generation available between $60/MWh and $10 000/MWh, and lower price generation either fully dispatched, ramp rate limited, trapped or stranded, the dispatch price reached $12 200/MWh. In response to the high price participants rebid capacity from high to low prices and the dispatch fell to -$941/MWh at 3 pm.

South Australia

There were three occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $68/MWh and above $250/MWh.

Tuesday, 1 March

Table 16: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
3 pm	2125.74	69.95	70.73	1941	1868	1875	2380	2414	2401

Conditions at the time saw demand and availability close to forecast four hours ahead. Prices were aligned with those in Victoria.

Table 17: Rebids for the 7 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.07 pm		Alinta Energy	Northern	123	<288	13 330	1405~A~DISPATCH $243 V 5PD $77.29~

At 2.55 pm there was a 29 MW demand increase (coinciding with the 280 MW demand increase in Victoria). With lower price generation either fully dispatched, ramp rate limited or trapped, the combination of the demand increase with the above rebid saw dispatch price reached $13 330/MWh, set by Northern. In response to the high price participants rebid capacity from high to low prices and the dispatch fell to -$1000/MWh at 3 pm.

Friday, 4 March

Table 18: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
4.30 pm	412.84	107.05	124.99	1908	1825	1916	2523	2512	2488
5 pm	437.34	79.99	124.99	1976	1854	1934	2533	2510	2491

Conditions at the time saw demand up to 122 MW higher than forecast and availability close to forecast four hours ahead.

A system normal constraint avoiding the overload of the Keith to Tailem Bend No.1 line was binding, which constrained off low-priced generation in the South East of South Australia and limited exports into South Australia from Victoria across Heywood to less than 300 MW. This constraint was not forecast four hours ahead.

Table 19: Rebids for the 4.30 pm and 5 pm trading intervals

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
1.48 pm		AGL Energy	Torrens Island	180	<80	>125	1345~A~060 UNFCAST NETWORK CONSTRANT~V>>V-JNWG_RADIAL_IA
1.49 pm		AGL Energy	Torrens Island	60	<80	>125	1345~P~010 UNEXPECTED/PLANT LIMITS~STABLE LOAD REQUIRED 100MW
3.58 pm	4.05 pm	Alinta Energy	Northern	155	-1000	13 330	1533~A~LONSDALE STARTED~
4.28 pm	4.35 pm	Alinta Energy	Northern	155	-1000	13 300	1625~A~DISPATCH $38.71 V 5PD $299.99~

As a result of the above rebids, the spot price was around $300/MWh for the first four dispatch intervals of the 4.30 pm trading interval.

At 4.25 pm, there was a 48 MW increase in demand. With low priced generation either fully dispatched or constrained off, the dispatch price increased to $1238/MWh. In the following dispatch interval, the dispatch price fell to $38/MWh as a result of rebidding by multiple participants into low prices.

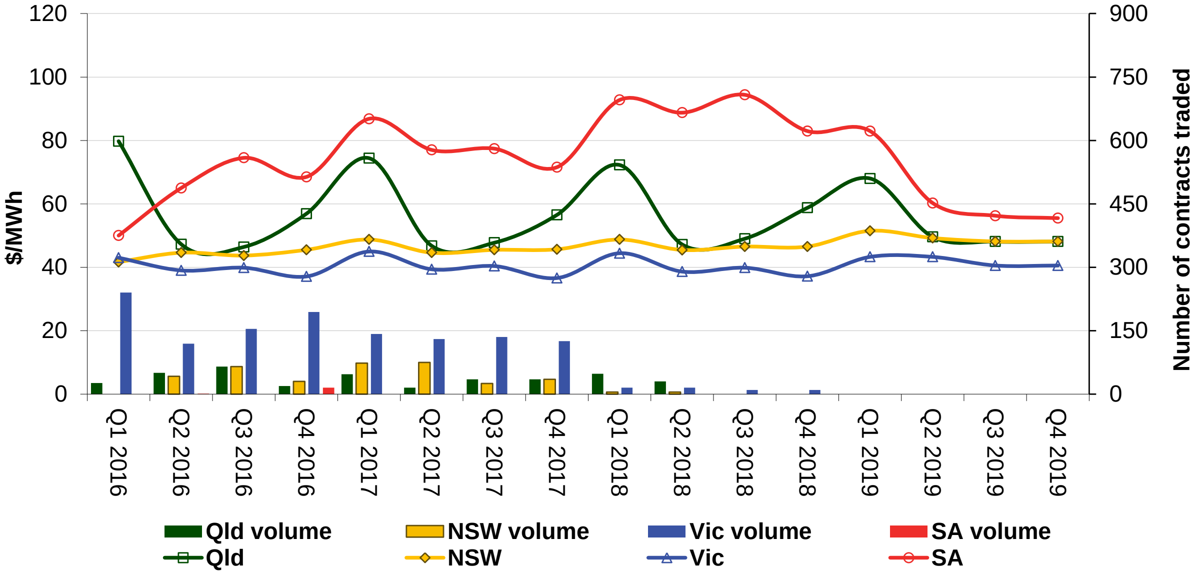
At 4.35 pm, as a result of Alinta Energy's rebid, and with low price generation either fully dispatched or constrained off, the dispatch price increased to $1223/MWh. In the following dispatch interval, the dispatch price fell to $36/MWh as a result of rebidding by multiple participants into low prices.

Between 4.35 pm and 4.50 pm, there was a gradual increase in demand in the region, with demand increasing by around 20 MW per dispatch interval. At 4.50 pm, as a result of the increases in demand and with low price generation either fully dispatched or constrained off, the dispatch price increased to from $47/MWh at 4.45 pm to $1239/MWh. In the following dispatch interval, there was a 52 MW reduction in demand (mostly attributed to an increase in non-scheduled generation) and the dispatch price fell to $45/MWh.

Financial markets

Figure 9 shows for all mainland regions the prices for base contracts (and total traded quantities for the week) for each quarter for the next four financial years.

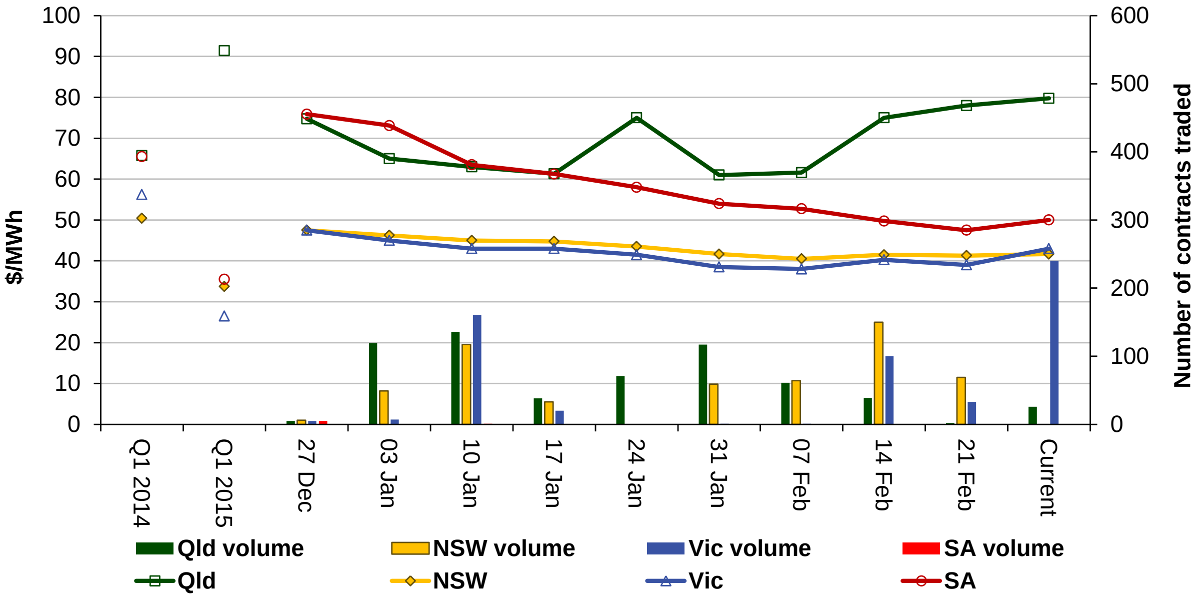
Figure 9: Quarterly base future prices Q1 2016 – Q4 2019



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Quarter 1 2016 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2014 and quarter 1 2015 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades.

Figure 10: Price of Q1 2016 base contracts over the past 10 weeks (and the past 2 years)



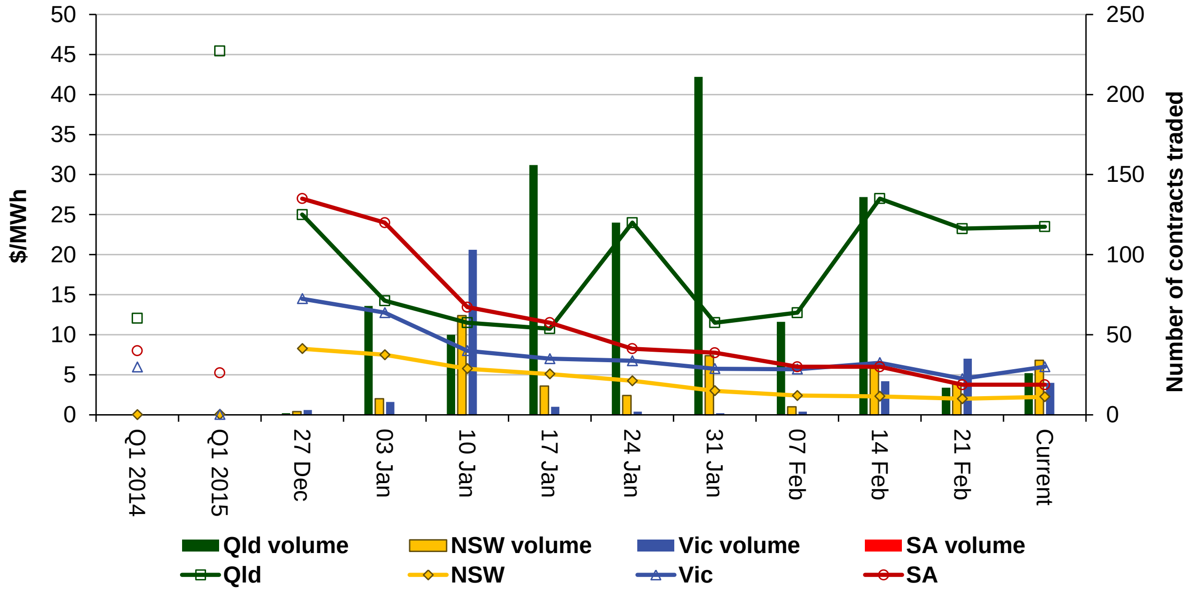
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the Industry Statistics section of our website.

Figure 11 shows how the price for each regional Quarter 1 2016 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2014 and quarter 1 2015 prices are also shown.

Figure 11: Price of Q1 2016 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
March 2016